Combustion Turbine

Combustion turbines (CTs) are typically used in medium to large landfill gas projects, where landfill gas volumes are sufficient to generate a minimum of 3 to 4 MW (i.e., where gas flows exceed approximately 2 million cfd). This technology is competitive in larger landfill gas electric generation projects because, unlike most IC engine systems, CT systems have significant economies of scale. The cost per kW of generating capacity drops as CT size increases, and the electric generation efficiency generally improves as well.

Simple-cycle CTs applicable to landfill gas projects typically achieve efficiencies of 20 to 28 percent at full load; however, these efficiencies drop substantially when the unit is running at partial load. Combined-cycle configurations, which recover the waste heat in the CT exhaust to make additional electricity, can boost the system efficiency up to approximately 40 percent, but this configuration is also less efficient at partial load [EPA, 1993]. One of the primary disadvantages of CTs is that they require high gas compression (165 pounds per square inch (psig) or greater), causing high parasitic load loss. This means that more of the plant's power is required to run the compression system, as compared to other generator options [WMNA, 1992]. An advantage is that turbines are much more resistant to corrosion damage than IC engines and have lower NO_x emission rates. In addition, combustion turbines are relatively compact and have low operations and maintenance costs in comparison to IC engines.

The installed capital costs for landfill gas energy recovery projects using simple cycle CTs are estimated to range from about $1,200 per net kW output to $1,700 per net kW output (1996 on-line date), for power projects at landfills ranging in size from 1 million metric tons to 10 million metric tons of waste in place, respectively. The costs include the CT, auxiliary equipment, interconnections, gas compressor, construction, engineering, and soft costs. (Chapter 5 provides more detail on technology costs.) The costs associated with the landfill gas collection system are not included in these cost estimates. For combined-cycle systems installed at landfills ranging in size from 5 million metric tons to 10 million metric tons of waste in place, the installed capital costs range from about $1,400 per net kW output to $1,700 per net kW output (1996 on-line date). A combined-cycle system is not likely to be economically competitive at landfills with less than about 5 million metric tons of waste in place.

Boiler/Steam Turbine

The boiler/steam turbine configuration is the least used of the three landfill gas power conversion technologies. It is applicable mainly in very large landfill gas projects, where gas flows support systems of at least 8 to 9 MW (i.e., where gas flows are greater than 5 mmcfd) [EPA, 1993]. The boiler/steam turbine consists of a conventional gas/liquid fuel boiler, usually a packaged unit, and a steam turbine generator that produces electricity. This technology usually requires a complete water treatment and cooling cycle, plus an ample source of process and cooling water. Boiler/steam turbine systems have a significantly higher cost per kW than either IC engines or CT systems, so only the largest landfill gas projects can afford to use this technology.

Fuel Cell

Fuel cells that run on landfill gas show great promise for power generation because of their modularity, small capacity, high efficiency, quiet operation, and low environmental impact.

It is for these reasons that fuel cells may be an ideal technology for generating power from landfill gas, once they have been fully demonstrated. While a few fuel cells running on natural gas are in commercial operation, fuel cells capable of using landfill gas are still in the development/demonstration phase. The biggest hurdle has been development of a feasible system for cleaning landfill gas prior to use in the fuel cell.

Fuel cells create energy by combining hydrogen (obtained from a fuel source such as landfill gas) and oxygen (supplied from the air) in an electrochemical reaction. Electricity is produced continuously, as long as there is a supply of fuel and air, at high efficiencies (e.g., 50 percent or more). There are three types of fuel cells suitable for power generation: phosphoric acid fuel cells; molten carbonate fuel cells; and solid oxide fuel cells. Phosphoric acid fuel cells (PAFC), which use hydrogen gas or reformed methanol as fuel sources, are the closest to commercialization for a landfill gas application. A 200-kW PAFC plant has been tested by the EPA at the Penrose Landfill in Sun Valley, California (Swanekamp, 1995].[5] Northeast Utilities installed the test unit at the Flanders Road Landfill in Groton, Connecticut in late 1995, and operation at the site began in June, 1996. Connecticut Light & Power, a subsidiary of Northeast Utilities, is operating and maintaining the test unit, and using 140 kW of the power it produces. In addition, the Department of Energy is working to demonstrate molten carbonate fuel cell technology for landfill gas applications.

Option 3: Upgrade to High-Btu Gas

A third project option is to upgrade the landfill gas to a high-Btu product for injection into a natural gas pipeline. Because of the relatively high capital cost of this option, it may be cost-effective only for those landfills with substantial recoverable gas (i.e., at least 4 million cfd [Maxwell, 1990]). This application requires relatively extensive treatment of the gas to remove CO_2 and impurities. In addition, gas companies require that gas injections into their pipeline systems conform with strict quality specifications, which can impose additional quality control and compression requirements. However, this may be an attractive option for some landfill owners, since it is possible to utilize all gas that is recovered.

Upgraded gas will require significant compression in order to conform with the pipeline pressure at the interconnect point. High pressure lines may require pressures of as much as 300 to 500 pounds per square inch (psig), while low and medium-pressure lines may require 10 to 30 psig.

Option 4: Alternative Uses

Other landfill gas utilization options include on-site use of the gas (which may be particularly appropriate for small landfills), heating greenhouses, producing carbon dioxide and other niche applications, or use as vehicle fuel, such as compressed natural gas and methanol. On-site and niche applications are in limited use. Vehicle fuel uses are currently in the commercialization phase, with only a few projects in place (Box 3.5 highlights two of these projects). These and other emerging applications must be evaluated on a case-by-case basis. Their likelihood of success at a particular landfill depends on site-specific factors such as the needs of the landfill, its size, and the quality of the gas. Regulatory developments, the goals of the owner/operator (e.g., an alternative, low emissions fuel source may be attractive for a municipality's fleet), and the needs of potential customers are also important. Because these applications are not fully commercial, they are not discussed extensively in this handbook.

[5] In July, 1996, Ron Spiegel of EPA's Office of Research and Development, was named a finalist for the 1996 Discover Magazine awards for his work in applying fuel cell technology to landfill gas.

Box 3.5 Landfill Gas as a Vehicle Fuel

CNG Application

The Los Angeles County Sanitation District's Puente Hills Landfill has succeeded in turning landfill gas into a clean vehicle fuel. The Sanitation District has installed a compressed landfill gas fueling station on-site and has converted a Sierra pickup truck, a Hercules water truck and the first of four garbage trucks to run on the compressed gas. This project has eliminated the need to flare excess gas from the landfill, and has reduced vehicle emissions at the same time.

Methanol Production

Using $500,000 in funding from the South Coast Air Quality Management District of California, TeraMeth Industries, Inc. modified its proprietary technology to produce Grade A methanol from landfill gas. Methanol (the critical ingredient in MTBE for federal and state reformulated gasoline requirements) is produced by first creating a synthesis gas which is then fed into a catalyst.

TeraMeth's California facility will produce 16,667 gallons per day of methanol when it begins operation in 1997 [Bonny, 1996].

3.2 CHOOSING AN ENERGY RECOVERY OPTION

The primary factor in choosing the right project configuration for a given landfill is the cost of the energy recovered. In general, sale of medium-Btu gas to a nearby customer, which requires minimal gas processing and typically is tied to a retail gas rate rather than an electric utility buyback rate, is the simplest and most cost-effective option. If a suitable customer is nearby and willing to purchase the gas, this option should be thoroughly examined. For many landfills, however, power production is and will continue to be the best available option. This section therefore focuses on the power production options.

At the foundation of any cost estimation is the expected amount of landfill gas that will be available for energy recovery. For initial assessments, an estimate of landfill gas quantity is all that is needed to estimate power potential. Assumptions regarding the Btu value of the gas, the efficiency of the generator, and the amount of downtime can then be used to convert the gas volume into power potential, as shown in Box 3.6.

This section compares the power production options on a unit cost basis for typical landfills with 1, 5, and 10 million tons of waste in place.[6] In addition to the landfill size and its associated gas production, a number of other factors are also important to project costs. These include: project scope (i.e., whether both a collection system and an energy recovery

[6] The amount of landfill gas associated with these landfill sizes was estimated using an EPA model that falls within the range of methods A and B presented in Chapter 2.

Box 3.6 Converting Gas Flow Rates into Power Potential

1) Estimate the Gross Power Generation Potential. This is the installed power generation capacity that the gas flow can support. It does not account for parasitic loads from auxiliary systems and equipment, or for system down time. Gross Power Generation Potential is estimated using the following formula:

kW = Landfill Gas Flow (cf/d) x Energy Content (Btu/cf) x 1/Heat Rate (kWh/Btu) x 1d/24hr

where:

- Landfill Gas Flow is the net quantity of landfill gas per day that is captured by the collection system, processed, and delivered to the power generation equipment (usually 75% to 85% of the total gas produced in the landfill)
- Energy Content of landfill gas is approximately 500 Btu per cubic foot
- Example Heat Rates are: 12,000 Btu/kWh for IC Engines and combustion turbines (above 5 MW);
  and
  8,500 Btu/kWh for combined-cycle combustion turbines.

2) Estimate the *Net Power Generation Potential*. This is the Gross Power Generation Potential less parasitic loads from compressors and other auxiliary equipment. Parasitic loads are estimated to range from 2% for IC engines to 6% or higher for combustion turbines.

3) Estimate the *Annual Capacity Factor*. This is the share of hours in a year that the power generating equipment is producing electricity at its rated capacity. Typical Annual Capacity Factors for landfill gas projects range between 80% and 95% and are based upon generator outage rates (4% to 10% of annual hours), landfill gas availability, and plant design. The assumed Annual Capacity Factor in the equation found in 4) is 90%. (See Table 3-2).

4) Estimate the *Annual Electricity Generated*. This is the amount of electricity generated per year, measured in kWh, taking into account likely energy recovery equipment downtime. It is calculated by multiplying the Net Power Generation Potential by the number of operational hours in a year. Annual operational hours are estimated as the number of hours in a year multiplied by the Annual Capacity Factor. Thus:

Annual Electricity Generated (kWh) = Net Power Generation Potential (kW) x 24 hr/day x 365 days/yr x 90%

system are required or only an energy recovery system); financing method; and available incentives to encourage landfill gas energy recovery. Each of these factors is discussed briefly below.

- **<u>Project Scope:</u>** Project scope depends upon the extent of landfill gas collection activities already underway (or planned) at the landfill, and it can have a significant impact on project costs. There are two typical landfill project scopes:

    - Total Project: refers to those projects at landfills with no current gas collection or energy recovery. For these projects, the entire project (including both gas collection and energy recovery systems) must be installed and the full costs must be recovered through the revenues from energy sales; and

    - Energy Recovery Project: refers to projects at landfills where gas collection systems have already been (or will soon be) installed. At these landfills, the costs associated with the collection system are sunk costs, and the only costs that need to be taken into consideration for the economic analysis are those associated with the additional equipment (i.e., the energy conversion system).

- **<u>Financing Method:</u>** As discussed in Chapter 6, there are many different financing methods available for landfill projects. The most common financing methods are private equity financing, "project finance" using a combination of debt and equity, and municipal bond finance, where public organizations issue bonds to raise project debt. The choice of financing method can have a significant impact on project costs; in general, municipal bond financing is much less expensive than financing with commercial debt and/or equity.

- **<u>Available Incentives:</u>** Because of the importance of encouraging landfill gas energy recovery, a number of federal, state and local incentives are available to these projects. The most important incentives are likely to be the IRS Section 29 tax credit, which may be available to private project developers, and the Department of Energy's Renewable Energy Production Incentive (REPI), which is available to public project developers. Both of these incentives can significantly improve project economics. The Section 29 tax credit is currently worth about ¢0.9 to ¢1.3/kWh, depending upon the efficiency of the generating equipment. The REPI is worth up to ¢1.5/kWh.

The cost per kilowatt hour for each power generation option — IC engine, combustion turbine, or steam turbine — will vary with the size of the landfill and these other factors, as shown in Table 3-3. Table 3-3 can be used to estimate the likely costs of a power generation project in the following way:

1. Determine whether it will be necessary to install both a gas collection system and an energy recovery system at the landfill, or only an energy recovery system. If both systems are required, examine the "Total Project" entries; if only an energy system is required, examine the "Energy Recovery Project Only" entries.

2. Determine whether municipal or private financing will be used. If the landfill is owned by a municipality, it is possible that municipal bonds can be issued to cover costs; otherwise, private financing will likely be required.

3. Determine whether financial incentives may be available, lithe project will be developed by a private developer and the gas sold to a third-party, Section 29 tax credits may be available. Public or non-profit landfill owners or developers, in contrast, may be eligible for the REPI program.

4. Determine the likely project size based on the amount of waste in place at the landfill.

Making these four decisions will enable a landfill owner/operator to determine likely power production costs for a range of generating technologies. In many cases, the lowest cost generating option will be selected. In some cases, however, it may be necessary to select a higher cost option due to other important considerations. IC engines may not be the best technology choice in certain areas, for example, due to their higher NOx emissions as compared to turbines.

As Table 3-3 illustrates, the estimated costs of power production can vary substantially depending on the factors presented above. At the high end, costs for a "Total Project" financed with private finance and unable to obtain any incentives could range from ¢7.4 to ¢7.9 per kWh for a 1 million ton landfill. The availability of municipal financing could reduce these costs by about ¢0.8 per kWh and developing an "Energy Recovery System Only" project could save approximately ¢2.5 per kWh. The lowest cost scenario — an "Energy Recovery System Only" project built with municipal financing and obtaining available incentives — has estimated costs ranging from ¢2.8 to ¢4.0 per kWh, which is less than half of the high cost case.

The same phenomenon is observed at the larger 5 and 10 million ton landfills. On the high end, "Total Project" costs at a 5 million ton landfill are estimated to range from ¢6.0 to ¢6.5 per kWh. This same project, implemented with municipal financing and available incentives, however, could cost only ¢4.0 to ¢4.3 per kWh. If the landfill already has (or plans to install) a gas collection system, the "Energy Recovery System Only" costs could be as low as ¢2.7 per kWh.

At the 10 million ton landfill, high end "Total Project" costs of ¢5.6 to ¢5.9 per kWh drop to ¢2.3 to ¢2.9 per kWh for an "Energy Recovery System Only" project with municipal bond financing and incentives. Interestingly, at this size the CT is more cost-effective than IC engine. In addition, the effects of economies of scale are evident, as the costs of similar projects at a 10 million ton landfill are an average of 20 to 30 percent lower than the 1 million ton landfill and 5 to 15 percent lower than the 5 million ton landfill.

It is important to recognize that the cost estimates presented here are rough estimates developed using assumptions related to "typical" landfills. Conditions at any particular site could be quite different and these site-specific conditions must be fully accounted for when developing detailed cost estimates for specific projects.

Part II of this handbook discusses in more detail the major steps involved in the development of a landfill gas energy recovery project, from estimating expenses and revenues to constructing and operating the project. In addition, EPA is developing a simple financial model that landfill owner/operators and others can use to estimate project costs and run sensitivity analyses. To obtain a copy of this model when it becomes available, call the EPA Landfill Methane Outreach Program Hotline at 1-888-STAR-YES.

Table 3-3 Estimated 1996 Costs of Electricity

	IC Engine		Combustion Turbine		Combined Cycle CT	
	Municipal Financing	Private Financing	Municipal Financing	Private Financing	Municipal Financing	Private Financing
Total Project without Financial Incentives (¢/kWh)						
1 Million	6.7	7.4	7.0	7.9	NA	NA
5 Million	5.5	6.0	5.6	6.2	5.8	6.5
10 Million	5.2	5.8	5.0	5.6	5.3	5.9
Total Project *with* Financial Incentives (¢/kWh)						
1 Million	5.2	6.1	5.5	6.6	NA	NA
5 Million	4.0	4.7	4.1	4.9	4.3	5.6
10 Million	3.7	4.5	3.5	4.3	3.8	5.0
Energy Recovery System Only *without* Financial Incentives (¢/kWh)						
1 Million	4.3	4.8	4.7	5.3	N.A.	N.A.
5 Million	4.2	4.6	4.2	4.7	4.7	5.3
10 Million	4.1	4.5	3.8	4.2	4.3	4.8
Energy Recovery System Only *with* Financial Incentives (¢/kWh)						
1 Million	2.8	3.5	3.2	4.0	NA	NA
5 Million	2.7	3.3	2.7	3.4	3.4	4.4
10 Million	2.6	3.2	2.3	2.9	2.9	3.9

NA: Technology was not evaluated at this landfill size.

The municipal finance scenarios were calculated using a capital charge rate of 0.111, which is based on financing with tax-exempt municipal bonds at an interest rate of 6.5%.

The incentive under the municipal finance plan scenario is the proposed federal REPI subsidy of 1.5 cents/kwh.

The private finance scenarios were calculated using a capital charge rate of 0.136, which is based on a project finance structure using: 80% debt, 20% equity; 9% interest in debt; 15% return on equity; 10 year depreciation.

Incentives under the project finance scenarios are IRS Section 29 Tax Credits, which are estimated to be worth their full value of $0.979/MMBtu in 1994, or 0.9 to 1.3 cents/kwh in 1996. In some cases, only a percentage of the tax credit value can be applied to a project if the credits are transferred between parties. For example, if 60% of the tax credit value can be applied to the project, then 1996 electricity costs would increase by 0.4 to 0.5 cents/kwh.

All scenarios include a royalty payment of 0.5 cents/kwh.

PART II

DETAILED ASSESSMENT OF PROJECT ECONOMICS

The Project Development Process

Part I **Preliminary Assessment of** **Project Options**
Determining if a Project is Right for Your Landfill
Determining What Project Configuration is Right for Your Landfill

⇓

Part II **Detailed Assessment of** **Project Economics**
Evaluating Project Economics
Assessing Financing Options
Selecting a Project Development Partner
Winning/Negotiating an Energy Sales Contract
Securing Project Permits and Approvals
Contracting for EPC and O&M Services

4. INTRODUCTION TO PART II: DETAILED ASSESSMENT OF PROJECT OPTIONS

Once the landfill owner/operator has determined that an energy recovery project is right for a particular landfill, and has made a preliminary assessment of the project options, he or she must conduct a more detailed assessment of the options, considering cost, financing, project structure, and other aspects of project development. This section contains information on each step in the assessment of project options, organized into the following chapters:

Chapter 5: Evaluating Project Economics

Chapter 6: Assessing Financing Options

Chapter 7: Selecting a Project Development Partner

Chapter 8: Winning/Negotiating an Energy Sales Contract

Chapter 9: Obtaining Project Permits and Approvals

Chapter 10: Contracting for EPC and O&M Services

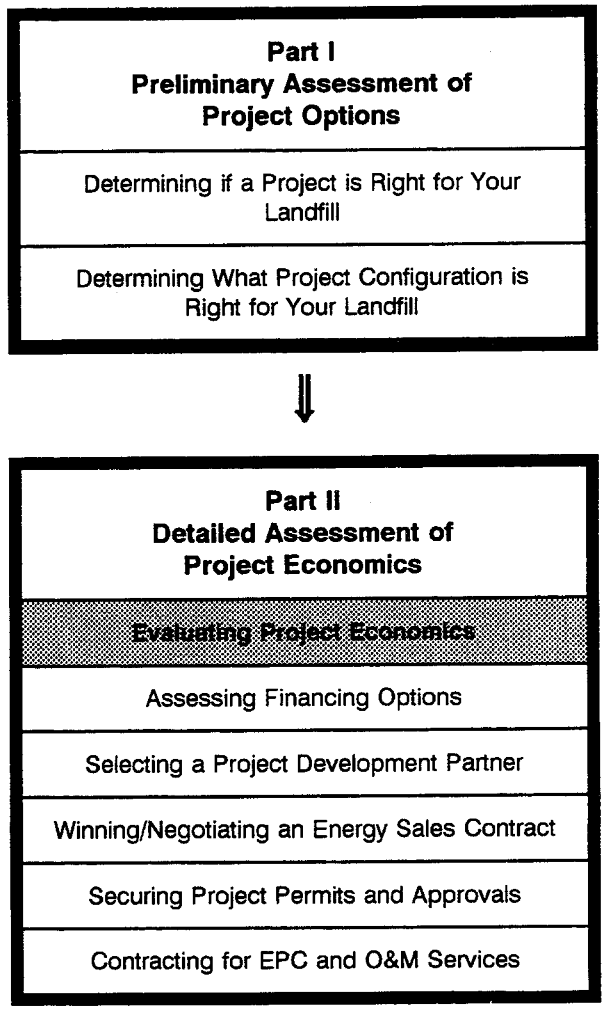
Each chapter contains the basic information — illustrated throughout with examples — needed to conduct one step in the project assessment process. By reviewing each chapter with a particular landfill in mind, an owner/operator can develop a solid understanding of the most cost-effective and appropriate options and project structure.

While this handbook provides valuable information to assist the owner/operator in evaluating choices and proposals, it does not serve as a technical guide to project development. The owner/operator may wish to consult a landfill gas energy recovery expert before beginning the development process.

5. EVALUATING PROJECT ECONOMICS

After the available quantity of landfill gas has been estimated and a preliminary assessment of project options has been completed, the next step in developing a landfill gas energy recovery project is a detailed economic assessment of converting landfill gas into a marketable energy product. The economics of a landfill gas-to-energy project depend on a number of factors, including landfill gas quantity, local energy prices, and equipment choice. This chapter presents a methodology for evaluating project economics, and shows sample economic evaluations for the principal energy recovery options. Once economic feasibility has been determined, the cost and financial performance data from the economic analysis can be carried forward to the assessment of financing options, partner selection, and negotiation of energy sales and equipment contracts, which are discussed in subsequent chapters.

The Project Development Process



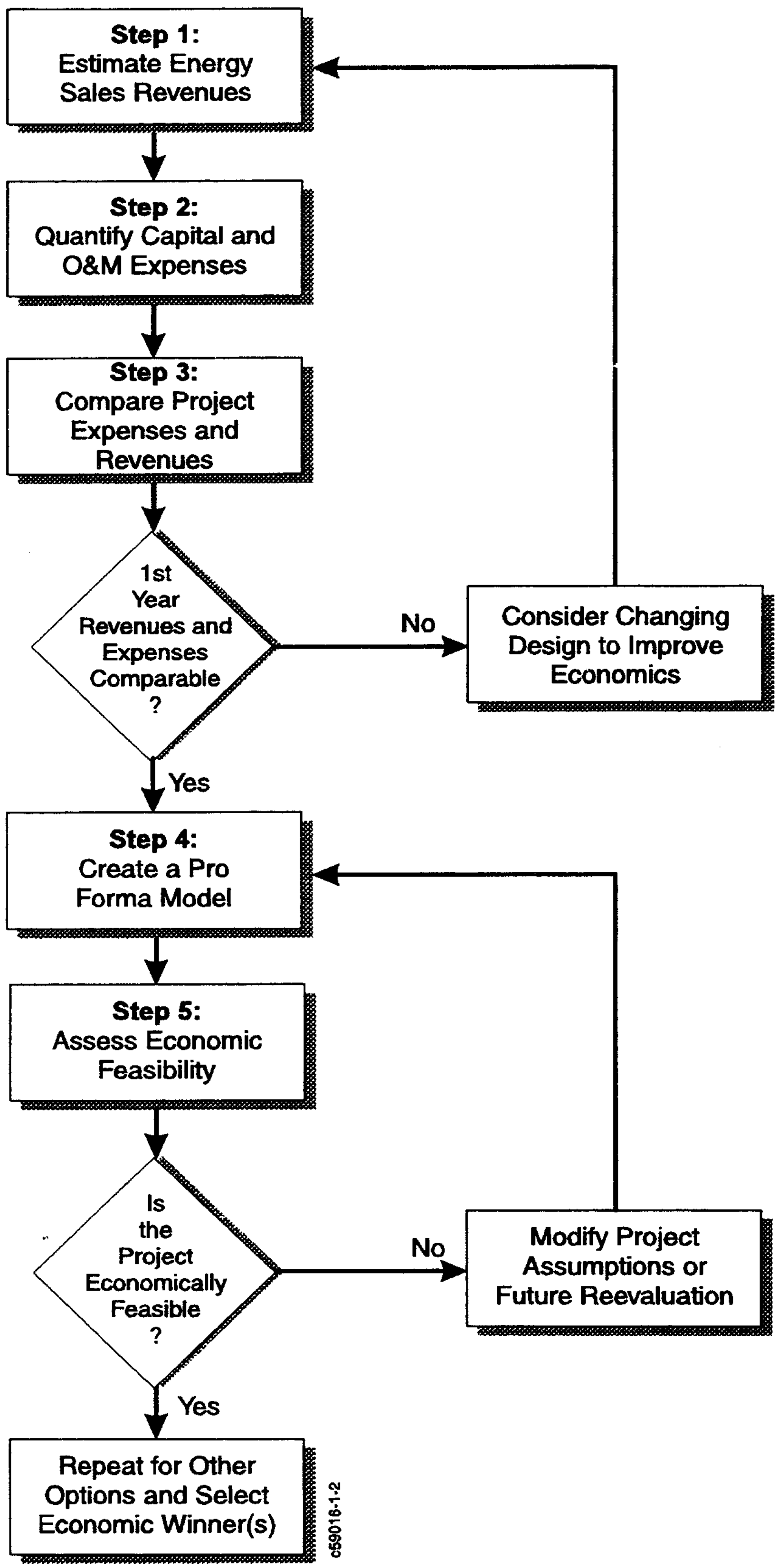
5.1 ECONOMIC EVALUATION PROCESS

An economic evaluation of a potential energy recovery project involves comparing the expenses of a particular project with the revenues that it is likely to receive. Figure 5.1 outlines the basic steps of the economic evaluation of energy recovery projects, and these steps are described in more detail below.

- Step 1. Estimate Energy Sales Revenues — Energy sales revenues include any cash that flows to the project from sales of electricity, steam, gas, or other derived products. Potential markets for energy products include electric utilities, municipal utilities, industrial plants, commercial or public facilities, and fuel companies. Revenues to the landfill gas energy recovery project are usually calculated based on the estimated quantity of energy delivered and the contract prices paid by the customer.

- Step 2. Quantify Capital and O&M Expenses — This step involves quantifying the capital costs and operation and maintenance (O&M) costs, plus in some cases landfill gas royalties and/or fees. Capital costs include not only the initial cost of the equipment, but also installation costs, debt service, owner's costs,

Figure 5-1 The Economic Evaluation Process



and returns on equity. Many of these costs vary with site-specific characteristics of the landfill.

- Step 3. Compare Project Expenses and Revenues — Once the estimates of the project's expenses and revenues have been made, an initial assessment of project economics can be made by checking to see if the first-year expenses and revenues are roughly equivalent. If they are comparable in the first year of project operation, then further economic evaluation is warranted. If not, it is usually necessary to re-examine technology, design, cost assumptions, and/or energy revenue assumptions to find ways to improve the economics.

- Step 4. Create a Pro Forma Model of Cash Flows — For a more accurate estimate of the probable lifetime economic performance of a project, the expenses and revenues should be calculated and compared on a year-by-year basis over the expected life of the project. This in-depth economic analysis, known as a pro forma, typically includes detailed calculations of project performance over time, escalation in project expenses and energy prices, financing costs, and tax considerations (e.g., depreciation, income tax).

- Step 5. Assess Economic Feasibility — Based on the pro forma model, the project economic feasibility can be assessed by calculating annual net cash flows, the net present value of future cash flows, and/or the owner's rate of return. These measures of financial performance are calculated over the life of the project and are the most reliable measures of economic performance. If these indicators are below the project proponent's criteria, he or she should reexamine the project for assumptions and/or options that can be modified.

If a landfill owner/operator has the opportunity to produce and sell more than one type of energy product, then the net cash flows of each option should be compared head-to-head to determine the best option. Cash flows of competing projects can be compared on an annual, net present value, and/or rate of return basis. After selecting an economic winner, the landfill owner/operator should then consider non-price factors including risks, ability to obtain financial backing, environmental performance, and reliability of assumptions. The option that produces the best financial performance while meeting the desired environmental, risk, and operating requirements is the overall winner.

The remainder of this chapter discusses the process of conducting a step-by-step economic analysis for the various landfill gas energy recovery options. The economic analyses presented in this chapter provide the landfill owner/operator with basic estimates of project costs and market prices for energy products. The landfill owner/operator can use the concepts presented to create his or her own economic analysis.

Example Landfill

Throughout this chapter, the key aspects of the economic evaluation process are illustrated with examples. These examples are based on a hypothetical landfill with 5 million metric tons of waste in place and a net sustainable landfill gas production level of 2,988 mcf/day. Box 5.1 presents the operating and cost assumptions that are used consistently in this chapter.

Appendix A contains the supporting performance and cost calculations for the 5 million metric ton example, and for two other landfill sizes — 1 million metric tons and 10 million metric tons. Appendix A also contains sample cost calculations for a medium-Btu gas sales project.

5.2 POWER GENERATION/COGENERATION

The opportunity to collect landfill gas and burn it to produce electric power is available to most landfill owners. Whether or not this option is economically feasible depends largely on local electricity prices, which vary dramatically across regions of the country. Other important factors include access to electricity purchasers, landfill gas volume, and technology selection. This section presents a sample economic analysis — using the five steps outlined above — for a landfill gas power generation project.

5.2.1 Step 1: Estimate Energy Sales Revenues

A landfill gas power project can have one or more sources of revenue, depending on whether it produces just electricity or also cogenerates steam and/or other thermal energy. An important potential source of revenue is use of a portion of the landfill gas or the derived electricity or steam to offset energy costs (e.g., natural gas, oil, electricity) at its own facilities. The savings that are achieved by offsetting energy purchases can be counted as a type of revenue. The following paragraphs describe the principal sources of revenue for power projects.

Electric Buyback Rate

The economic factor that will usually have the greatest impact on a power project's economic feasibility is the local electric utility's buyback rate (i.e., the price the utility is willing to pay for the electricity produced by a non-utility electric generator). The buyback rate reflects the utility's own avoided costs of generating electricity, incorporating the cost of building new generating capacity if needed. The costs of generating electricity, and thus buyback rates, vary considerably among utilities and regions. Factors such as fuel mix, availability of cheap hydropower, utility financial health, and reserve margins have a large influence over local electricity costs and the rate (i.e., price) at which electric utilities will buy electricity from a landfill gas project.

U.S. electric utilities are currently required by the Public Utility Regulatory Policies Act (PURPA) to buy electricity from qualifying facilities, which include small power producers and cogenerators. Small power producers are defined as electric generating facilities that produce up to 80 MW and use mostly non-fossil fuels. Landfill gas energy recovery facilities are eligible to be classified under PURPA as small power producers. PURPA dictates that electric utilities must buy electricity at a rate no higher than the utility's "avoided cost," which is the cost that the utility would pay to generate the next increment of electricity using its own resources.

Avoided costs are typically filed with the state utility regulators on a regular basis, and some utilities publish buyback tariffs, accompanied by standard offer contracts, based on their avoided cost. (More information on standard offer contracts is provided in Chapter 8.) Utility buyback tariffs regularly include an avoided energy price, and some utilities also pay an additional component for their avoided capacity costs. The energy price component is based on

Box 5.1 Assumptions for 5 Million Metric Ton Landfill Example

Operating Assumptions

Waste in place:	5 million metric tons
Collection efficiency:	85%
Net sustainable LFG production:	2,988 mcf/day
LFG calculation method:	EPA Report to Congress Equation [EPA]
Electric output calculation:	kw = (cf/hr) x (500 Btu/cf) / (Btu/kwh)
Electric heat rate (Btu/kwh):	12,000 for IC engine & CT 8,500 for combined cycle CT
Online date:	June, 1996
Annual capacity factor:	80%
Annual full load operating hours:	7,008

Capital Cost Assumptions

Energy conversion system cost includes engine/generator, auxiliary equipment, interconnections, gas compressor, and construction costs.

LFG collection system includes collection wells, blower, and flare system.

Engineering costs = 5% of installed equipment costs.

Soft costs include owners' costs (e.g., legal, permitting, insurance, taxes), escalation during construction, interest during construction, and contingency.

Incremental Capital Requirement = Total Costs - LFG Collection System Costs.

Cost of Electricity

Cost of Electricity = Capital component + O&M component + Royalty

Capital Charge Rate assumptions:

Project Finance Case

- 20 year project life
- 80% debt, 20% equity
- 9% interest on debt
- 15% return on equity
- 10-year depreciation

Muni Finance Case

- 20 year project life
- 100% tax-exempt bonds
- 6.5% interest on debt
- No income tax

Royalty/gas payment estimated at 0.5 ¢/kWh (about 10% of project revenues).

the utility's fuel costs and operation and maintenance costs, which may vary depending on the time of day or year. The capacity price component is usually fixed, based on the utility's cost of building or buying additional capacity. Only utilities that actually need additional generating capacity will typically offer a capacity price component.

The avoided energy price component alone may not be enough to support a landfill gas power project. In these cases, landfill gas power project developers must seek electric utility customers that need additional capacity and are offering a capacity price component as well. Some utilities might offer a premium for renewable energy or environmentally beneficial projects such as landfill gas energy recovery. In some cases the utility's published tariff will be acceptable, but more often the project developer must attempt to negotiate a more favorable rate. (Chapter 8 discusses the different avenues to obtaining power sales contracts.)

In addition to possible sales to an electric utility, state regulators may allow direct electricity sales to one or more local customers. These sales are usually conditioned on the fact that they are limited to a number of contiguous neighbors. If such sales are allowed, the landfill gas power project must negotiate a rate with the customer. It is usually necessary to offer the customer an electricity rate that provides a discount over the rate currently paid to the local utility, unless the project is offering something that the local utility does not, such as higher reliability. Since retail electric rates are typically higher than the buyback rates offered, this type of arrangement can be very attractive to the seller and the buyer.

Historically, landfill gas power projects have received electric buyback rates ranging from ¢2/kWh to ¢10/kWh, averaging about ¢6/kWh. However, newer projects generally report receiving only ¢3/kWh to ¢4/kWh [EPA, 1993]. The chief reasons for lower rates in recent years are a slowdown in the rate of electric demand growth, and an abundance of generating capacity in some parts of the country (e.g., Southwest, New England). Generally, significant economic potential for landfill gas power projects exists where electric buyback rates are above ¢4/kWh, although technology improvements, emerging applications, and requirements to recover landfill gas for environmental reasons are increasingly making projects viable at rates below ¢4/kWh [EPA, 1993].

Displacement of On-Site Energy Purchases

It may be practical to use a portion of the generated electricity to displace some or all of the electricity purchases at commonly-owned facilities near the project site. For example, for a county-owned landfill, opportunities for displacement savings may include energy use at county office buildings, maintenance shops, water treatment plants, community centers, and correctional facilities. Displacement savings are calculated by determining the amount of on-site electricity usage that can be met by the energy project, then determining the cost of that electricity usage, based on the current retail rates or recent electric bills. The retail rates paid by the landfill owner/operator to the utility are typically higher than the buyback rate offered by the utility to purchase the power.

Displacement savings may also be achieved when the landfill owner/operator can use a portion of the landfill gas produced to offset natural gas or oil purchases at nearby facilities under the same ownership. The economic incentive for the owner/operator to try and offset these fuel costs will mainly be determined by the landfill's proximity to facilities that use natural gas or oil to meet process or heating needs. The savings possible from these offsets will

Box 5.2 Displacement of Energy Purchases at the Prince George's County Correctional Complex

The Brown Station Road Landfill (4 million tons waste in place and growing) in Prince George's County, Maryland provides landfill gas to meet the electrical and heating needs of the County Correctional Complex. This energy recovery system generates electricity using three 850-kw IC engine generators and also delivers medium-Btu gas to two conventional boilers located at the correctional complex. The three electric generators provide almost all of the correctional complex's electrical needs; excess electricity generated by the project is sold to the local electric utility (PEPCO). The boilers, which were originally designed to burn No. 2 fuel oil or natural gas, were adapted for landfill gas fuel and provide heat and hot water for the correctional complex. The project configuration was selected from among several options based on an economic comparison which examined lifetime costs and revenue to the county.

The project displaces most of the county's electricity and heating fuel costs associated with the correctional complex. The county estimates that the gross benefits are about $1.2 million per year in energy cost savings [Augenstein and Pacey, 1992].

depend on the existing fuel costs of the facilities and the amount of landfill gas that can be used by the facilities. Box 5.2 describes a landfill gas energy recovery project that displaces boiler fuel purchases and generates electricity for a Prince George's County, Maryland facility.

Thermal Energy Revenues

Landfill gas energy recovery projects can generate thermal energy such as steam or chilled water for use in nearby industrial plants or commercial facilities (e.g., hospitals, office buildings, hotels, universities). The economic incentive to cogenerate steam and other forms of thermal energy along with electricity using a cogeneration configuration is determined mainly by the potential customer's existing costs of generating thermal energy, and by the project's proximity to the customers. Typical steam costs range from $1.5 per million Btu (MMBtu) to $6/MMBtu, depending on the existing fuel and technology being used. Steam generation from waste fuels, wood, and sometimes coal can achieve costs at the low end of this range, while gas- and oil-fired steam is usually more expensive. Landfill project owner/developers should expect to offer some discount, often on the order of 5% to 30%, over a potential customer's current steam cost in order to be attractive.

Sample Calculation of First Year Revenues

For the hypothetical 5 million metric ton landfill described in Box 5.1, revenues are assumed to be created by generating electricity for: (1) sale to the local electric utility; and (2) displacement of retail electric purchases at a municipal office building. This example assumes that the electric buyback rate in 1996 is ¢4.8/kWh. It also assumes that there is a nearby office building, owned by the landfill owner/operator, that consumes 3 million kWh per year at a retail rate of ¢5.9/kWh in 1996. Table 5-1 presents a calculation of first-year revenues, which range from $1.7 million for an IC engine system to $2.3 million for a combined-cycle CT system. The

Table 5.1 Estimated First–Year Power Project Revenues at Example Landfill

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
PROJECT OPERATING DATA					
Net sustainable landfill gas production	mcf/day	2,988	2,988	2,988	(a)
Gross electric output	kW	5,188	5,188	7,324	
Net electric output	kW	4,934	4,727	6,763	
Annual electricity generated	kWh	34,577,472	33,126,816	47,395,104	
Annual electricity sold					
Net electricity sold to utility	kWh	31,577,472	30,126,816	44,395,104	
Electricity used on–site	kWh	3,000,000	3,000,000	3,000,000	(b)
ELECTRICITY PRICES					(b)
Buy–back price	c/kWh	4.8	4.8	4.8	
Retail price	c/kWh	5.9	5.9	5.9	
ANNUAL EXAMPLE REVENUES					
Electricity Sales to Utility in 1st Year	$000	$1,522	$1,452	$2,140	(c)
Electricity Sales On–Site in 1st Year	$000	$177	$177	$177	(d)
Total Annual Revenues	**$000**	**$1,699**	**$1,629**	**$2,317**	
Revenues per kWh sold	c/kWh	4.9	4.9	4.9	(e)

Notes:

(a) Calculated using statistical model 4.2 in EPA Report to Congress. [EPA] The resulting methane production estimate is within the range predicted by the models presented in Part I.

(b) Assumed for example purposes.

(c) Product of utility sales kWh and assumed 1996 buyback electricity rate of 4.8 c/kWh.

(d) Product of on–site sales kWh and assumed 1996 retail electricity rate of 5.9 c/kWh.

(e) Total annual revenues divided by total kWh generated. Note that this shows potential revenues, not the cost of generating electricity from landfill gas.

combined-cycle CT produces more revenues than the other technologies because it generates more electricity, but the Step 2 analysis will show that the combined-cycle CT is also more expensive to build. The first-year revenues amount to ¢4.9/kWh for all three technologies on a per kWh basis, calculated by dividing the annual revenues by the total kWh generated and sold. In Step 3 this revenue estimate will be compared against the cost of generating electricity from landfill gas, which varies significantly among the technologies as described in the next section.

5.2.2 Step 2: Quantify Capital and O&M Expenses

To evaluate the economic feasibility of a landfill gas power project, the project expenses must be subtracted from revenues to determine potential gains (or losses). The chief project expenses are the amortization of up-front capital costs and the annual O&M expenses. Some projects have other expenses such as payment of fees or royalties for landfill gas rights. The following sections describe the different categories of project expenses.

Capital Costs

The total capital requirement for a landfill gas power project includes the costs of the major equipment (e.g., engine, CT), as well as the costs associated with the auxiliary equipment, construction, emissions controls, interconnections, gas compression and treatment, engineering, and "soft costs." Soft costs typically include up-front owner's costs (e.g., development staff, legal, permitting, insurance, property tax), escalation during construction, interest during construction, and owner's contingency, all of which are real costs incurred prior to and during the construction process.

The costs of the landfill gas collection system (e.g., equipment, installation, soft costs) can be excluded from the economic analysis if the collection system is either already in place or required by air emissions regulations. The energy recovery system can then be evaluated using an incremental cost approach. Under the incremental cost approach, the collection system costs are not included because these are sunk costs that would be incurred whether the recovered landfill gas is put to use or just flared. In the 5 million metric ton landfill example, the total cost includes the costs associated with the energy conversion system plus the landfill gas collection system, while the incremental cost does not include the capital or O&M costs associated with the landfill gas collection system.

Capital costs for landfill gas power projects vary widely depending on landfill size, conversion technology, and project design. Table 5-2 presents the estimated capital costs of landfill energy recovery systems for landfills with 1, 5, and 10 million metric tons of waste in place. For these hypothetical energy recovery projects beginning operation in 1996, the total capital requirement is estimated to range between $1,595/kW and $2,423/kW, and the incremental capital requirement is estimated to range between $1,109/kW and $1,691/kW[1]. These cost data are expressed in as-spent dollars, which means that equipment cost

[1] Not included in the capital cost data are preliminary project development expenses, the major component of which is landfill gas quantity testing. The most reliable method of testing is to drill test wells and conduct a pump test. Test wells typically cost between $5,000 and $10,000 per well [Smithberger, 1994; Merry, 1994], and the number of wells required to accurately predict landfill gas quantity will depend on a number of factors such as landfill size and waste homogeneity.

escalation (e.g., inflation) prior to and during construction is included in the cost estimate. As the cost data show, the capital cost per kW generated ($/kW) generally decreases with increasing project size, owing mainly to economies of scale, particularly for the CT-based technologies.

In the example cost calculation for the 5 million metric ton landfill producing about 3 million cf of landfill gas per day in 1996, the total capital requirement ranges from $1,675/kW for an IC engine system to $2,025/kW for a combined-cycle CT system, including the cost of the gas collection system (see Table 5-3). On an incremental basis, the capital requirement ranges from $1,1771kW for the IC engine to $1,658/kW for the combined-cycle CT. These costs are in as-spent dollars, reflecting a June 1996 on-line date. A boiler/steam turbine system would not be economically competitive at this size, but boiler/steam turbine system costs would probably become competitive at larger gas flow rates above roughly 5 to 7 million cf/day.

Although capital cost is the major determinant of the cost of generating electricity from landfill gas projects, the technology with the lowest capital cost is not always the choice. A good example is the 10 million metric ton landfill case presented in Appendix A. In that case, the IC engine has the lowest capital cost, but after O&M and royalty expenses are taken into account, the CT option yields the lowest cost of electricity. Other factors such as reliability and emissions also should be considered when deciding among technologies (see Part I for more on technology issues).

O&M Expenses

The O&M expenses vary considerably among projects due to different equipment types and gas treatment processes. Typically, O&M expenses include both fixed and variable expenses, as described in Box 5.3. Fixed O&M expenses are predictable and are not dependent on the amount of time that the project operates or the amount of electricity generated. Variable O&M expenses are usually dependent on the amount of time that the project operates, which can be measured by the amount of electricity (i.e., kWh) produced.

The total generator system O&M costs for IC engines are about ¢1.8/kWh in 1996 dollars [EPA, 1993]. The O&M costs associated with the gas collection system are about ¢0.5/kWh [EPA, 1993]. The O&M costs for CT-based systems are generally lower than those for IC engine-based projects [Wolfe and Maxwell].

Royalties/Gas Payments

The project developer may also need to pay for the gas received in the form of royalty payments to the owner of the gas rights and/or as gas payments to a gas company that collects and delivers the landfill gas. Royalties can be viewed as compensation for gas rights or as a financial incentive for allowing the project to be developed. Historically, power project owners have paid royalties to landfill owners equal to 10% to 12.5% of project revenues [Jansen, 1992; Augenstein and Pacey, 1992]. In recent years, the tightening of project financial margins has caused a reduction or elimination of pure royalty payments to landfill owner/operators. Royalties that are still paid are usually paid by the gas company.

Gas payments are made by generation companies or other end users for delivery of the gas. Gas payments are necessary in order for the project to take advantage of certain tax

Table 5.2 Estimated Power Project Capital Costs for Three Landfill Sizes

			CAPITAL COSTS				
LANDFILL SIZE Waste in Place	Estimated Net Sustainable LFG Production (mcf/day)	Net Electric Output (kW)	Installed LFG Collection System ($/kW)	Installed Energy Conversion System ($/kW)	Total Soft Costs + Engineering ($/kW) (a)	Total Capital Requirement ($/kW)	Incremental Capital Requirement ($/kW) (b)
1 million metric tons							
IC Engine	642	984	$638	$1,052	$310	$2,000	$1,283
Combustion Turbine	642	963	$652	$1,412	$359	$2,423	$1,691
5 million metric tons							
IC Engine	2,988	4,934	$423	$958	$294	$1,675	$1,177
Combustion Turbine	2,988	4,727	$442	$1,153	$334	$1,928	$1,409
Combined Cycle CT	2,988	6,763	$309	$1,360	$356	$2,025	$1,658
10 million metric tons							
IC Engine	5,266	8,709	$413	$919	$263	$1,595	$1,109
Combustion Turbine	5,266	8,344	$431	$1,037	$288	$1,756	$1,249
Combined Cycle CT	5,266	12,008	$300	$1,208	$306	$1,813	$1,458

Notes:

Source is cost calculation tables for each size landfill (see Appendix A).
All costs are based on net electric (kW) output.

(a) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 – 24 mos) and interest during construction.

(b) Excludes capital and soft costs associated with the LFG collection system.

Table 5.3 Estimated Power Project Capital Costs at Example Landfill

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
OPERATING DATA					
Net electric output	kW	4,934	4,727	6,763	
On-line date		6/96	6/96	6/96	
EQUIPMENT & INSTALLATION COSTS					
Energy Conversion System ($1994)	$000	4,725	5,450	9,200	
LFG Collection System ($1994)	$000	2,088	2,088	2,088	
Engineering ($1994) @ 5.0%	$000	341	377	564	
CAPITAL REQUIREMENT					
System cost ($1994)	$000	7,154	7,915	11,853	
Soft Costs	$000	1,109	1,200	1,841	
Total Capital Requirement	$000	8,263	9,115	13,694	
(as-spent dollars, 1996 on-line date)	$/kW net	1,675	1,928	2,025	
Incremental Capital Requirement	$000	5,807	6,659	11,216	(a)
(as-spent dollars, 1996 on-line date)	$/kW net	1,177	1,409	1,658	

Notes:

See Chapter Appendix for notes on these calculations.

(a) Excludes capital and soft costs associated with the LFG collection system.

Box 5.3 Classification of O&M Expenses

O&M expenses include both fixed and variable expenses, as shown below.

Fixed O&M expenses	Variable O&M expenses
Labor	Periodic maintenance and overhauls
Property taxes	Water
Insurance	Consumables (e.g., lubricating oil, hydraulic fluid, filters)
Administrative expenses	
Spare parts	
Fees	
Emissions offsets	

The distinction between fixed and variable expenses is important, because fixed O&M expenses are incurred regardless of the amount of electricity generated.

credits, because the gas must be sold to an unrelated party (e.g., power generator, industrial user). Tax credits are discussed in more detail later in this chapter.

The 5 million metric ton landfill example includes an annual royalty payment/gas payment equal to about 10% of revenues. Including a royalty/gas expense demonstrates the economic effect that royalties have; namely, they make landfill gas projects more expensive. In the example, paying the royalty increases costs by ¢0.5/kWh, which could make the difference between an economically attractive project and an unattractive project. In the future, landfill owner/operators may have additional incentive to forego royalty payments because of the environmental benefit of a landfill gas recovery project.

Estimating the Cost of Electricity

The cost of generating electricity (c/kWh) from a landfill gas power project is equivalent to the sum of capital expenses, O&M expenses, and royalty/gas expenses (if any), divided by the kWh of electricity delivered. Estimating this cost has two steps:

(1) Amortize capital costs and divide by the annual kWh produced; and
(2) Add O&M and royalty expenses.

Each of these steps is described below and illustrated with an example.

Step 1: Amortize Capital Costs: Capital costs are commonly "levelized," or amortized in equal annual amounts over the economic life of the project (i.e., over the period that the project will generate revenues). If the productive landfill life is 20 years, then a typical term for the levelized capital cost calculation would be 20 years. For the purposes of economic analysis, the capital costs are often amortized using a capital charge rate (CCR). A CCR is used to convert the installed cost into a levelized capital cost that can be charged to the project in each year of the project life. The CCR is the levelized percentage of the total capital that must be recovered in each year to cover:

- return of equity;
- return on equity;
- interest on debt;
- depreciation;
- general and administrative expenses;
- property tax; and
- income tax.

The CCR can be calculated by estimating annual interest and return on equity payments on the outstanding loan value over the life of the project (similar to a home mortgage) and adding annual amounts for depreciation, expenses, and taxes. The main variables in the CCR calculation are the debt/equity ratio and interest rates. The CCR for a privately financed landfill gas-to-energy project will be higher than the CCR for a project financed with municipal bonds (More detailed information regarding CCRs under different financing scenarios is contained in Chapter 6.):

- **Project Finance Case:** A CCR of approximately 0.136 would result in the case where a project is financed with a debt/equity ratio of 80/20, a nominal interest rate on debt of 9%,[2] an after tax return on equity of 15%, and a 10-year tax depreciation. (To take advantage of 10-year depreciation, the project life is assumed to be just under 20 years.)[3]

- **Municipal Bond Finance Case:** Thus, a CCR of approximately 0.111 would result from the case where a project is financed with 100% municipal tax-exempt bonds that have a 6.5% interest rate.

To obtain a levelized capital cost (LCC) in ¢/kWh units, the annual cost calculated as described above must be divided by the expected operating hours per year as follows:

LCC = Installed Cost x CCR / (CF x Hours per Year) x (¢100/$) (Eq. 5.1)

where:

LCC	=	levelized capital cost (¢/kWh)
Installed Cost	=	total or incremental capital requirement ($/kW)
CCR	=	capital charge rate

[2] Interest rates are determined by the prevailing rate indicators (e.g., U.S. treasuries, prime rate, LIBOR) and a host of project- and lender-specific factors. When this document was written, rates for nonrecourse debt for a strong landfill gas project ranged from 9% to 9.8%. [Seifullin, 1995; DePrinzio, 1995] Increasing interest rates by 1% would cause the cost of electricity to increase by 2% to 3%.

[3] Landfill gas energy recovery projects appear to be eligible to use 10-year depreciation for income tax purposes. [Jansen, 1992; Mumford and Lacher, 1993] Property with a life of 16 years or more, but less than 20 years, can use the 10-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule. [RIA, 1992]

CF	=	annual average capacity factor
Hours per year	=	8,760

Using the 5 million metric ton landfill example, the levelized capital cost for the IC engine option would be ¢3.2/kWh, calculated as follows using an 80% capacity factor[4]:

¢3.2/kWh = ($1,675/kW x 0.136) / (80% x 8760 hrs) x (¢100/$)

If the project were financed with 100% tax-exempt municipal bonds (CCR = 0.111), the levelized capital cost would be ¢2.7/kWh.

Step 2: Add O&M Expenses: This step is straightforward — add the estimated O&M expenses and royalty expenses (if any) to the capital expense to get the total cost of electricity.

Based on the capital, O&M, and royalty expenses discussed above, the total first year cost of generating electricity from the 5 million metric ton landfill in 1996 are presented in Table 5-4. As the table shows, the cost of the conversion system plus the gas collection system could range from ¢6.0/kWh to ¢6.5/kWh if the project were financed with 80% debt and 20% equity. Financing 100% of the project costs with tax-exempt municipal bonds would achieve a cost of electricity ranging from ¢5.5/kWh to ¢5.8/kWh. The incremental cost of electricity, which excludes collection system costs, would be approximately 20% to 25% lower, or ¢4.6/kWh to ¢5.3/kWh for the project finance case, and ¢4.2/kWh to ¢4.7/kWh for the municipal bond finance case. [Note that these costs of electricity include a royalty payment of ¢0.5/kWh and do not include the effects of incentives, which could trim another ¢1/kWh or more off the electricity cost if applicable (incentives are factored into the calculation in Step 3).]

The IC engine appears at this landfill size to have a slight cost advantage over the CT and a substantial advantage over the combined-cycle CT, owing mainly to the IC engine's lower engine and gas compressor costs, and gas compressor auxiliary load. However, the IC engine loses some of its advantage because of higher O&M costs.

5.2.3 Step 3: Compare Project Expenses and Revenues

As a first cut at assessing a particular project's economics, first-year expenses and revenues are often compared to see if a project configuration warrants further analysis. At this point it is important to include any tax credits or other incentives in the economic assessment. If first-year project revenues are comparable with expenses, making sure to take into account any tax credits that are available, then it is advisable to proceed to the next step: creating a pro forma model of project cash flows. If the estimated revenues fall significantly short of the project costs, one or both of the following two options should be pursued:

1) Look for additional sources of revenue (e.g., on-site sales, thermal sales) or alternative customers (e.g., electric utilities, municipal utilities) that may offer a higher electricity price; and/or

2) Change the project configuration (e.g., size, technology, equipment vendor, energy outputs) and re-examine the economics.

[4] See Box 3.6 in Chapter 3 for a discussion of capacity factors.

Table 5.4. Estimated Cost of Electricity Production for Three Project Configurations at Example Landfill

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
Total Electricity Cost in 1996					
Project Finance Case (80% debt, 20% equity)	c/kWh	6.0	6.2	6.5	
Municipal Finance Case (tax–exempt bonds at 6.5%)	c/kWh	5.5	5.6	5.8	
Incremental Electricity Cost in 1996					(a)
Project Finance Case (80% debt, 20% equity)	c/kWh	4.6	4.7	5.3	
Municipal Finance Case (tax–exempt bonds at 6.5%)	c/kWh	4.2	4.2	4.7	

Notes:

See Chapter Appendix for notes on these calculations.

All cost estimates include a 0.5 c/kWh royalty payment. Tax incentives and subsidies are not included.

(a) Incremental Electricity Cost does not include capital and O&M costs associated with LFG collection system.

Tax Credits/Incentives

Tax credits and federal incentive payments can significantly improve project economics, and help to justify an otherwise marginal project. Currently, federal tax credits listed under Section 29 of the Internal Revenue Code are available for the recovery and use of unconventional gas fuels such as landfill gas. Additionally, the "Renewable Energy Production Incentive" (REPI) program, which was mandated under the 1992 Energy Policy Act and is being implemented by the U.S. Department of Energy, provides an incentive to publicly owned facilities that generate electricity from renewable energy sources such as landfill gas. The applicability of these incentives depends on the structure of the project and the owner/operators' tax situation. Therefore, a full understanding of the tax laws and how they may be applied is critical to ensuring a project's ability to take advantage of the incentives.

Section 29: The Internal Revenue Service (IRS) Section 29 tax credit, currently due to expire in the year 2007, is available to landfill gas projects that are operating before June 30, 1998. This tax credit has been extended several times by the U.S. Congress since its initial inception, but there are no guarantees that the extensions will continue. The credit is worth $5.83 per barrel of oil-equivalent (on a MMBtu basis) and is adjusted annually for inflation [Conversation with Tommy Thompson, U.S. Internal Revenue Service, April 1996]. The current value of the credit is $1,001 per MMBtu [Conversation with Tommy Thompson, U.S. Internal Revenue Service, April 1996]. At full value, this converts to about 0.9¢ to 1.3¢/kWh for a typical landfill gas electricity project, depending on the efficiency of the generating equipment used.

The Section 29 tax credits apply only to landfill gas that is produced and then sold to an unrelated third party (for example, when landfill gas is sold as a medium-Btu fuel to an industrial customer) [RIA, 1992]. As a result of this stipulation, project developers may bring in or create a separate company when developing power projects in order to take advantage of the credits. Several project structures exist that would allow a landfill gas project to benefit, either directly or indirectly, from the tax credits. Three such structures are presented in Box 5.4. Depending on the structure used, the project may receive only a fraction of the value of the tax credits. For example, if a tax-paying company takes responsibility for gas collection and sells the gas to a power project, the collection company is entitled to the Section 29 tax credits. However, if this company cannot fully use the credits, as is often the case, the company might transfer the credits to outside investors who can use them. Usually the gas collection company must "sell" the tax credits at a discounted price, leaving the collection company with as little as 60% of the full value of the tax credits.

REPI: Section 1212 of the Energy Policy Act of 1992 stipulated that a cash subsidy of 1.5¢ per kWh (adjusted annually for inflation) would be available to renewable energy power projects owned by a state or local government or nonprofit electric cooperative, that are first used during the period October 1993 through September 2003 [Federal Register, July 19, 1995]. Solar, wind, geothermal (except dry steam geothermal), and biomass (including landfill gas, but excluding municipal solid waste) projects are defined to be renewable energy projects.

The availability of funding for REPI payments is subject to annual appropriation by Congress. Approximately $2.2 million was appropriated for the program for fiscal year 1995, and $3 million was appropriated for 1996 [Klunder, 1995]. Payments will be made first (and on a pro rata basis if necessary) to qualified renewable energy facilities

Box 5.4 Examples of How A Project Can Be Structured to Take Advantage of Section 29 Tax Credits

Privately Owned Landfill:

Scenario One:

- The landfill owner owns and operates the gas collection system (GASCO), and sells the gas to the developer for use in the energy recovery project (GENCO).
- The GENCO is owned and operated by a developer who is unrelated to the landfill owner.

Result: The landfill owner receives gas revenues and tax credits, which can be used or sold along with the GASCO to another party.

Publicly Owned Landfill:

The following scenarios describe structures that enable a landfill owner who cannot take direct advantage of tax credits (e.g., a municipality) to benefit from the transfer of credits.

Scenario One:

- An entity (GASCO) unrelated to the landfill owner purchases the gas rights from the landfill and operates the gas collection system. It sells the gas to the energy recovery project (GENCO).
- The GENCO is owned and operated by a developer who is unrelated to the landfill owner.

Result: The landfill owner receives a one-time payment for its gas rights, and the owner of the GASCO receives the tax credits.

Scenario Two:

- The landfill leases gas rights, for a "production fee," to an unrelated party (GASCO) who sells the gas to the energy recovery project (GENCO).
- The GENCO is owned and operated by a developer who is unrelated to the landfill owner.

Result: The landfill owner receives production payments and a share of the tax credits. The GASCO receives the majority of the tax credits.

In many of these cases, the developer of the energy recovery project and the purchaser/lessor of the gas rights may have overlapping ownership of up to 50%. [Martin, 95] using solar, wind, geothermal, and closed-loop biomass technologies.[5] Payments will then be made (on a pro rata basis if necessary) to all other qualified renewable energy facilities [10 CFR, Part 451] including landfill gas-to-energy facilities. The 1995 appropriation was enough to make all approved payments.

According to the rules governing the REPI program, projects must apply annually for the payments, which may continue for up to ten years. Applications for energy produced in a fiscal year must be submitted to the Department of Energy during the period October 1 through December 31 of the following fiscal year [10 CFR Part 451].

Example Calculation of Project Cash Flow (First Year)

An estimate of first year cash flow and economic viability is obtained by subtracting the first-year expenses from revenues, and adding available tax credits/incentives. If this calculation yields an amount of zero or greater (i.e., surplus cash flow), the assumed revenues can support the project expenses, as well as meet the project's financing requirements (e.g., a 15% return on equity in the project finance case). The financing requirements are included in this analysis as part of the project expenses. A negative result indicates a cash flow shortfall, which means that expenses will not be covered or debt service requirements will not be met in the first year. Since this calculation only provides a rough indication of economic viability, the most important result is simply whether or not the calculation yields a non-negative amount.

Continuing the 5 million metric ton landfill example, the assumed electric buyback rate of ¢4.8/kWh would be capable of supporting various project configurations depending on the financing assumptions and the cost basis assumption, as shown in Table 5-5. As shown in the table, all three technologies are estimated to be viable on an incremental cost basis for both the project finance and municipal bond finance cases. However, on a total cost basis, only the IC engine power configuration appears viable in the project finance case. In contrast, the cost advantages of municipal bond financing (tax exempt) allows all three technologies to be viable even under a total cost basis. This analysis demonstrates that the availability of municipal bond financing has an important effect on the economic viability of the technology options.

It is clear that for the example landfill, the IC engine power configuration appears most promising at this stage of the analysis, so the analysis of this option should proceed to Step 4. Because the CT option is relatively close to the IC engine under all scenarios, it would be reasonable to carry the CT forward for further evaluation in Step 4 as well. The combined-cycle CT should only be considered if municipal bond financing is an option.

Landfill gas power project economics have the potential to improve over time, but future performance must nevertheless be carefully examined. Economics can improve, because most of the costs are fixed (e.g., capital and gas collection costs) and not subject to significant escalation over time. Only the O&M costs are expected to increase significantly. Project revenues, which are driven by buyback rates, can increase over time and should more than offset any O&M increases. However, these positive effects can be easily negated by declining gas flows in later years, because the project will have diminished revenues (see

[5] Closed-loop biomass means any organic material from a plant which is planted exclusively for purposes of being used to generate electricity [10 CFR, Part 451].

Table 5.5 First Year Project Revenues and Expenses for Three Project Configurations at Example Landfill

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
REVENUES	c/kWh	4.9	4.9	4.9	
PROJECT FINANCE CASE					
Expenses (including Owner's Return)					
Total	c/kWh	6.0	6.2	6.5	
Incremental	c/kWh	4.6	4.7	5.3	
Revenues Minus Expenses					
Total	c/kWh	(1.1)	(1.3)	(1.6)	
Incremental	c/kWh	0.3	0.2	(0.4)	
1996 Tax Credit	c/kWh	1.3	1.3	0.9	(a)
Estimated Surplus (Shortfall) Cash Flow After Taxes and Owner's Return					
Total Cost Basis	c/kWh	0.2	0.0	(0.7)	
	$000	$69	$0	($332)	
Incremental Cost Basis	c/kWh	1.6	1.5	0.5	
	$000	$553	$497	$237	
MUNICIPAL BOND FINANCE CASE					
Expenses (including financing costs)					
Total	c/kWh	5.0	5.1	5.3	
Incremental	c/kWh	3.7	3.7	4.2	
Revenues Minus Expenses					
Total	c/kWh	(0.1)	(0.2)	(0.4)	
Incremental	c/kWh	1.2	1.2	0.7	
1996 REPI Subsidy	c/kWh	0.0	0.0	0.0	
Estimated Surplus (Shortfall) Cash Flow After Taxes and Financing Expenses					
Total Cost Basis	c/kWh	(0.1)	(0.2)	(0.4)	
	$000	($35)	($66)	($190)	
Incremental Cost Basis	c/kWh	1.2	1.2	0.7	
	$000	$415	$398	$332	

Notes:

(a) In many cases, only a fraction of the tax credit gets applied to the project. If only 60% of the available credit gets applied, then the project becomes more expensive by about 0.5 c/kWh, or $173,000 per year.

See Appendix A for notes on calculations.

Chapter 3 for more on project sizing).

The results of the analysis are, of course, driven by the key assumptions that affect costs and revenues, including: incentives, royalty payments, capital and O&M costs, electric buyback rate, financing method, and annual capacity factor. In this example, the full value of tax credits or subsidies contribute 0.9¢/kWh to 1.5¢/kWh to project cash flows, and all scenarios include a royalty/gas payment expense of 0.5¢/kWh.

5.2.4 Step 4: Create a Pro Forma Model of Project Cash Flows

After an initial comparison of expenses and revenues has demonstrated that a particular project configuration could be competitive (e.g., IC engine, CT), the next step is to create a pro forma model of project cash flows over the life of the project. This type of cash flow model is known as pro forma because it usually contains several standard items including a listing of financial assumptions and operating parameters, energy pricing data, calculation of annual expenses and revenues, an income statement, a cash flow statement, and financial results (see Box 5.5). An income statement usually lists the elements of project revenues and expenses, and shows a calculation of operating income, depreciation, taxes, and net book income. A cash flow statement typically shows project cash flows including pre-tax and after-tax cash flows, and distributions to project owners. Financial results include debt coverage ratios, rate of return (ROR), and net present value (NPV).

Box 5.5 The Pro Forma

The elements of a well-designed pro forma include:

- Project specifications and cost data
- Operations summary (e.g., kwh generated, Btu delivered, gas consumed)
- Financing and depreciation summary (e.g., interest rates, schedules)
- Price escalators for fuels, consumables, services, equipment
- Operating expense calculation (annual costs for royalties, fuel, O&M)
- Revenue calculation (annual revenues from sales of electricity, energy)
- Financing costs (e.g., interest and principal payments, investor's cash flow)
- Income statement (calculation of operating income, book income)
- Income tax and tax credit calculation
- Cash flow statement (e.g., pre-tax and after-tax cash flow calculations)
- Financial performance calculation (e.g., debt coverages, ROR, NPV of cash flows)

A well-designed pro forma should give the owner/developer a clear idea of project revenues, expenses, and sensitivities, and it can also serve to convince investors of project financial viability and returns. Preparing a detailed pro forma is an important step in ensuring the financial feasibility of a landfill gas-to-energy project. The pro forma model is usually created by the project developer using a computer spreadsheet format, which makes it easy to change inputs and assumptions if needed. This feature also makes the pro forma a useful tool for testing the project's economic sensitivity to alternative assumptions and options.

A pro forma will yield a much more reliable assessment of economic viability than the first-year comparison. Therefore, it is generally recommended that a pro forma be developed for all options that achieve positive or close-to-positive results in Step 3.

5.2.5 Step 5: Assess Economic Feasibility

The key financial results of a pro forma model are used to assess the economic feasibility of a power project. Economic feasibility is usually measured by indicators such as debt coverage ratios, ROR on equity, and NPV. The debt coverage ratio, which is the annual ratio of operating income to the debt service requirement, is a measure of the project's ability to meet its debt repayment requirements, and is usually expected to be in the range of 1.3 to 1.5. Lenders often view projects with debt coverage ratios below 1.3 as having a high risk of defaulting on loan repayment, which can make financing difficult. The ROR on equity and the NPV of owner's cash flows are two measures of the financial returns to the project owner. The owner's rate of return on equity ranges from approximately 12% to 18% for most types of power projects.

An acceptable owner's ROR for a particular project is a function of project risks and the owner's objectives. If the landfill owner views the project mainly as a cost-effective pollution control measure, then financial returns are not the only consideration and a ROR of 12% or less may be acceptable. Likewise, if risks have been removed because extensive testing has been done or permits are in hand, then lower RORs may be acceptable. However, if uncertainties such as unconfirmed gas flow rates or potential permitting difficulties are present, then the owner/developer may expect a higher ROR to compensate for the risks.

5.3 SALE OF MEDIUM-BTU GAS

If there is a suitable buyer nearby, direct sales of medium-Btu gas is generally the most economic recovery option, because it entails minimum processing requirements and capital costs. The suitability of a potential buyer depends largely on two considerations: (1) the buyer's proximity to the landfill and (2) the buyer's gas requirements.

The proximity of a potential customer to the landfill is critical because the cost to deliver the gas may be prohibitive if the customer is located far from the landfill. Ideally, the customer will be no further than one to two miles away. If there are no potential customers nearby, it may be possible to entice new industrial facilities to locate near the landfill by offering a low cost fuel.[6]

The total *annual* gas or steam requirements of a potential customer are important, since they will determine whether landfill gas production rates will support the entire needs of the customer or only a portion. For example, a five million metric ton landfill could support the processing needs of a large kiln operation, while a one million metric ton landfill may only provide enough gas to supplement needs during peak periods. When evaluating the needs of a customer who will be using landfill gas in boilers to generate steam, a general rule of thumb is

[6] New industries that are searching for a suitable facility location often work through local or state economic development specialists to identify candidate sites. Therefore, educating economic development specialists about the benefits of using landfill gas as a fuel so they can offer its advantages to potential customers may be worthwhile.

that approximately 10,000 pounds per hour of steam can be provided by every one million metric tons of landfill waste in place.[7]

A potential buyer's *seasonal* gas demand is also important due to the nature of landfill gas production. If a customer has only an intermittent gas load, much of the landfill gas recovered will be flared rather than sold, since landfill gas storage is not economical. A baseload gas user which uses gas on a continuous basis is usually preferred over an intermittent user, such as a facility that uses gas mainly for seasonal heating needs. It is more difficult to justify the economics of selling gas to an intermittent user, because gas sales revenues are reduced during non-heating seasons and the landfill gas must be flared or used elsewhere.

Using landfill gas as a medium-Btu fuel in boilers that create steam to meet process or space heating needs is one of the simplest and most common direct use applications. Other industrial applications include drying operations, kiln operations, and cement and asphalt production. If one of these applications provides only a seasonal market for the landfill gas, multiple uses may be combined to achieve a continuous base load. Box 5.6 describes how one company successfully created a year-round demand for its landfill gas production by combining the demands of its asphalt manufacturing operation with its space heating needs in the winter months. Another landfill gas application that may be ideal is to provide supplemental fuel to waste-to-energy plants, which are often located near landfills. For example, at the 45-MW Ridge waste-to-energy plant in Florida, landfill gas from the adjacent landfill comprises five percent of total fuel input on a heat-input basis [Swanekamp, 1994].

The economic viability of the project can be determined once a potential gas user has been identified using the steps described below.

5.3.1 Step 1: Estimate Energy Sales Revenues

Revenues for a medium-Btu gas project come from gas sales to a direct use customer. Potential landfill gas customers include industrial energy users, commercial buildings, universities, incinerators, and district heating systems. Typically, medium-Btu gas customers will buy landfill gas at a price that is no higher than their current delivered price of natural gas on a Btu basis, since landfill gas combustion may require burner retrofits, controls, and maintenance that natural gas does not. In fact, landfill gas project owner/developers should expect to offer landfill gas at a discount off the customer's current natural gas price; discounts of approximately ten to twenty percent are common in existing projects. Delivered natural gas prices vary by location and customer type. For example, the price paid by a large industrial gas user will likely be less than that of a customer who only uses gas for space heating purposes such as commercial buildings and district heating systems. Box 5.7 illustrates these price variations, which should be kept in mind when negotiating with potential customers.

Displacement savings, realized by using landfill gas to offset natural gas purchases at facilities owned by the landfill owner/operator, should also be credited to the project.

Tax credits or other incentives may be used to supplement gas revenues. However, if the tax credits are to be used by a third party developer, they may not yield full face value to the project since there are soft costs (i.e., legal and transaction fees) associated with placing

[7] This rule of thumb assumes that steam is supplied at 50 psig, saturated.

Box 5.6 Multiple End Uses of Landfill Gas Create a Baseload Demand for Fred Weber, Inc.

Fred Weber, Inc., a cement and asphalt producer, collects landfill gas from a landfill near St. Louis, Missouri and directly uses the medium-Btu gas in three different, seasonal applications, for savings of about $100,000 per year.

- In the summer months, landfill gas is burned in the aggregate dryer at the firm's asphalt plant which is located adjacent to the landfill.
- In the winter months, Fred Weber, Inc. uses landfill gas in its concrete plant to heat water for the preparation of ready-mixed concrete.
- Landfill gas is also used to heat the firm's adjacent commercial greenhouse.

By using landfill gas in complementary applications, Fred Weber, Inc. has created a baseload demand for its landfill gas supply.

[Mahin, 1991]

Box 5.7 Natural Gas Price Variations by Customer Type

Natural gas consumers can either purchase their own gas supplies and then pay the local distribution company (LDC) a delivery charge, or they can purchase delivered supplies directly from the LDC. Most large industrial and commercial consumers choose the former purchase alternative, since it is usually less expensive than buying from the LDC.

Regardless of the purchase strategy used, large industrial customers typically pay less for natural gas than other types of consumers:

	Industrial	Commercial	Residential
Average Price ($/mcf)	3.00	5.22	6.89

All dollar values are in 1994 dollars.

[Energy Information Administration, 1995]

the ownership of the gas rights and collection system with an independent party. In addition, if the company cannot fully use the credits, the company may transfer the credits to an outside investor. These outside investors usually buy the credits at a discounted price, leaving the sellers with as little as 60% of the full value of the tax credit.

5.3.2 Step 2: Quantify Capital and O&M Costs

The gas collection costs for a medium-Btu gas sales project would be similar to those incurred in a power project, although gas processing costs would probably be much less, since only minimal clean-up is usually required for direct use applications. The capital costs associated with delivering landfill gas to the customer would normally include pipeline construction costs (about $250,000 to $500,000 per mile, installed), additional gas compression costs, and metering. If there are low points in the pipeline which would allow moisture to accumulate, then the costs of installing dehydration equipment may also be incurred.

The customer may incur capital costs if equipment retrofits are necessary in order to burn landfill gas. For example, due to the lower flame temperature of landfill gas as compared to natural gas, lower boiler superheater temperatures may be experienced and thus a larger boiler superheater could be required [Eppich and Cosulich, 1993]. Retrofit costs will vary, since most require customized installation. For example, one project reported that new rotary kiln burners would cost $30,000 each [LaReaux, 1995], while boiler burner retrofits may range in cost from $120,000 to $300,000 [Brown, 1995]. The landfill project may assume some of these retrofit costs, as was the case in the AT&T project described in Box 5.8.

Box 5.8 Medium-Btu Gas Sales to AT&T

Network Energy of Ohio, owner of landfill gas rights at a landfill near Columbus, Ohio, is selling landfill gas to a nearby AT&T Network Wireless Systems plant. The AT&T plant uses the landfill gas as boiler fuel to generate about 40,000 pounds of steam per hour for plant heating, process uses, and hot water heating. Use of the landfill gas enables AT&T to reduce the purchases of its normal boiler fuel — natural gas. Even with some natural gas still used to supplement the landfill gas supply, AT&T expects to achieve annual fuel savings of about $100,000.

To make the medium-Btu purchase attractive to AT&T, Network Energy paid the $1 million cost of building a 1.5-mile pipeline from the landfill to the plant and converting one AT&T boiler to burn landfill gas. A custom low-NOx burner was designed by Coen Company to burn a controlled mixture of landfill gas and natural gas. The burner control system is able to respond to changes in landfill gas line pressure and Btu content.

The agreement between Network Energy and AT&T provides that all key boiler equipment installed in the conversion is owned by AT&T. In addition, AT&T had input in the design process and obtained the air permit for the modified burner. Network Energy is responsible for ensuring that all other environmental conditions are met [Source: Power, April 1994].

Table 5-6 shows the total capital costs for the example 5 million metric ton landfill, serving a gas consumer who is assumed to be located one mile away. The cost of providing gas to this customer is estimated to be $3.39 million, including the cost of the gas collection system. These costs (in as-spent dollars, reflecting a June 1996 on-line date) would increase with longer pipeline distances.

Table 5.6 Estimated Medium-BTU Project Capital Costs at Example Landfill

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
OPERATING DATA			
Net sustainable landfill gas production	mcf/day	2,988	2,988
Net fuel output (MMBtu)	MMBtu/day	1,494	1,494
On-line date		6/96	6/96
Capacity factor (lifetime annual average)		90%	40% (a)
Annual full load operating hours	hours	7,884	3,504
Annual volume of gas sold	MMBtu	490,811	218,138
EQUIPMENT & INSTALLATION COSTS			
Gas Delivery System ($1994)			
Condensate removal/filtration	$000	15	15
Compressor/Blower station	$000	100	100
Pipeline interconnect	$000	350	350
Fuel burning equipment conversion	$000	150	150
Gas delivery system cost ($1994)		615	615
LFG collection system cost ($1994)	$000	2,098	2,098
Engineering ($1994)	$000	136	136
CAPITAL REQUIREMENT			
System cost ($1994)	$000	2,848	2,848
System cost ($1996)	$000	3,051	3,051
Soft costs($1996)			
Owners costs, escalation, interest		190	190
Contingency @5.0%		153	153
Total Soft Costs	$000	343	343
Total Capital Requirement			
(as-spent dollars, 1996 on-line date)	$000	3,394	3,394
Incremental Capital Requirement	$000	769	769 (b)

Notes:

See Chapter Appendix for notes on these calculations.

(a) Assumes baseload user has a year-round need for gas, and heat load user only uses gas in the five winter months.

(b) Excludes capital and soft costs associated with the LFG collection system.